2.0 Energy Alternatives Evaluated

The specific energy alternatives addressed in this analysis include the following:

- Energy conservation and efficiency
- Noncombustible renewable energy resources
- Combustible renewable energy sources
- Nonrenewable combustible energy resources

2.1 Energy Conservation and Efficiency

2.1.1 Overview

Energy efficiency means doing the same work-or more-with less energy. Energy efficiency improvements can free up existing energy supply, so energy efficiency can be considered part of a state's energy resources.

SME's member cooperatives have implemented a program of incentives for its customers to install energy efficient appliances. SME's member cooperatives have complied with a state mandate to invest a portion of the total revenues collected in a conservation program. This practice has been in place since 1997. Examples of the conservation programs consist of rebates on ground source heat pumps and the installation of energy efficient retrofit lighting.

2.1.2 Commercial Availability

All energy efficiency options described are readily available to customers of the SME member cooperatives.

2.1.3 Technical Feasibility

All energy efficiency options described are proven technologies.

2.1.4 Cost-Effectiveness

The cost-effectiveness of energy efficiency and incentive programs can be quite variable and highly dependent on the effectiveness of the program approach. Energy efficiency incentive programs have been found to be cost-effective in terms of reducing load growth.

2.1.5 Environmental Compatibility

Promotion and use of energy efficient programs generally have neutral or beneficial effects on the environment by slowing down the need for additional fossil fueled power sources. Air pollutants are lessened and water quality of native streams is not affected. The installation of equipment is almost universally replacement in kind or is located on the end user's property thus resulting in little to no additional land use (footprint) issues. Permits that may be required are typically obtained at the local agency level through the residential or commercial / industrial building permit process.

2.1.6 Southern Montana Electric G&T

Through its member cooperatives, the SME system offers energy efficiency and rebate programs. The programs range from rebates for energy efficient appliances to replacement lighting programs to help customers reduce energy consumption.

2.1.7 Capable of Fulfilling Purpose and Need

Energy efficiency programs are capable of lessening the impact of electrical demand and reducing the energy requirements for future load growth. These programs will aid in reducing the capacity of future additional generation facilities. However, the ability to eliminate the need for additional generation capacity within the SME service area by 2009 is highly unlikely. These programs should be considered as parallel activities to securing additional generation to meet the projected demand within the SME service area.

2.2 Renewable Non Combustible Energy Resources

The renewable non combustible energy resources evaluated in this section are wind, hydroelectric, solar (photovoltaic [PV] and thermal), and geothermal. The electric power cost projections for these energy technologies are shown in Table 2-1 below.

2.2.1 Wind

Overview

The greatest advantage of wind power is its potential for large-scale, though intermittent, electric generation without emissions of any kind. In addition, over the years, wind energy production cost has benefited from improvements in technology and increased reliability. The development of wind power is increasing in many regions of the United States, including Montana. Installed wind electric generating capacity now totals 6,374 mW and is expected to generate approximately 16.7 billion kWh. Wind energy installations across the United States are expected to reach 8,000 MW by the end of 2010 (Ref. 12). Technological advances have improved the performance of wind turbines and driven down their cost. In locations where the wind blows steadily, wind power has been shown to compete favorably with coal and natural gas fired power plants based on receiving the federal Renewable Energy Production Incentive (REPI).

TABLE 2-1
Electric Power Cost Projections for Renewable Non-Combustible Energy Resources
Levelized Costs* for *New Utility Generating Plants in Northwest Power Pool (NWPP) Region

	Levelized Costs ($/mWh)				
		Solar			
Cost Component	**Wind**	**Photovoltaic**	**Thermal**	**Hydroelectric**	**Geothermal[1]**
Capital	35.9	N/A	N/A	17.0	N/A
Fixed O&M	7.7	N/A	N/A	2.6	N/A
Variable/Fuel	7.0	N/A	N/A	4.0	N/A
Total Busbar Cost[2]	50.6	350	105	23.6	65

Source for Wind Costs: U.S. Department of Energy (DOE) Energy Information Administration (EIA) Annual Energy Outlook 2004 with Projections to 2025. Based on the National Energy Modeling System (NEMS).

Source for Photovoltaic Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information – Photovoltaic Technology website: (http:/lwww.eere.energy.gov/state_energy/technology_overview.cfm?techid=1).

Source for Thermal Solar Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information – Concentrating Solar Power Technology website: (http:/lwww.eere.energy.gov/state_energy/technology_overview.cfm?techid=4).

Source for Hydroelectric Costs: U.S. DOE Idaho National Engineering and Environmental Laboratory (INEEL) Hydropower Program website: (http:/hydropower.inel.aov/facts/costs-graphs.htm).

Source for Geothermal Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information - Geothermal Technology website: (http:/lwww.eere.energy.gov/state_energy/technology_overview.cfm?techid=5).

Notes:

[1] Commercial geothermal resources not available in the SME service area.

[2] Busbar Cost - wholesale cost to generate power at the plant.

$/mWh - dollars per megawatt hour

O&M - operations and maintenance

The outlook for wind energy remains favorable because of the technology's economic competitiveness, growing demand for electricity, and effective renewable energy policies and incentives.

Wind turbines are mounted on a tower to capture the most energy. At 100 feet (30 meters) or more aboveground, they can take advantage of the faster and less turbulent wind. Turbines catch the wind's energy with their propeller-like blades. Usually, two or three blades are mounted on a shaft to form a rotor.

A blade acts much like an airplane wing. When the wind blows, a pocket of low-pressure air forms on the downwind side of the blade. The low-pressure air pocket then pulls the blade toward it, causing the rotor to turn. This is called lift. The force of the lift is actually much stronger than the wind's force against the front side of the blade, which is called drag. The combination of lift and drag causes the rotor to spin like a propeller, and the turning shaft spins a generator to make electricity.

There are four main parts to a wind turbine: the base, tower, nacelle, and blades. The blades capture the wind's energy, spinning a generator in the nacelle. The tower contains the electrical conduits, supports the nacelle, and provides access to the nacelle for maintenance. The base, made of concrete and steel, supports the whole structure.

Wind turbines can be used in off-grid applications, or they can be connected to a utility power grid. For utility-scale sources of wind energy, a large number of turbines are usually built close together to form a wind farm. These turbines each require about a quarter-acre of land, which includes land for the turbine and any access roads. As a result, turbines fit well onto agricultural land without taking the land out of production. The land mass used to support the installation of a wind turbine is the area necessary for the turbine base. All of the land between two (or more) turbine installations is available for agricultural activities.

Commercially Available

Wind power is available commercially. Installed wind electric generating capacity now totals 6,374 mW and is expected to generate approximately 16.7 billion kWh. Wind energy installations across the United States are expected to reach 8,000 MW by the end of 2010 (Ref. 12).

Technical Feasibility

Wind resources can be used with both large wind turbines for utility applications and with small wind turbines for onsite generation. As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (the lowest) to class 7 (the highest). In general, a wind power class 4 or higher can be useful for generating power with large (utility-scale) turbines, and small turbines can be used at any wind speed. Class 4 and above are considered good resources.

The map of Montana Annual Average wind power (Figure 2-1) shows general wind power classes for the state of Montana and indicates that SME's territory has potential wind resources throughout the area.

Areas of the land that have a wind power class of 4 or higher are present within the SME service territory. This portion of the SME service area has the potential to support large-scale wind farm facilities with an estimate annual capacity factor of approximately 30 percent. Therefore, it is technically feasible to develop wind farms within the general SME service area.

Cost-Effectiveness

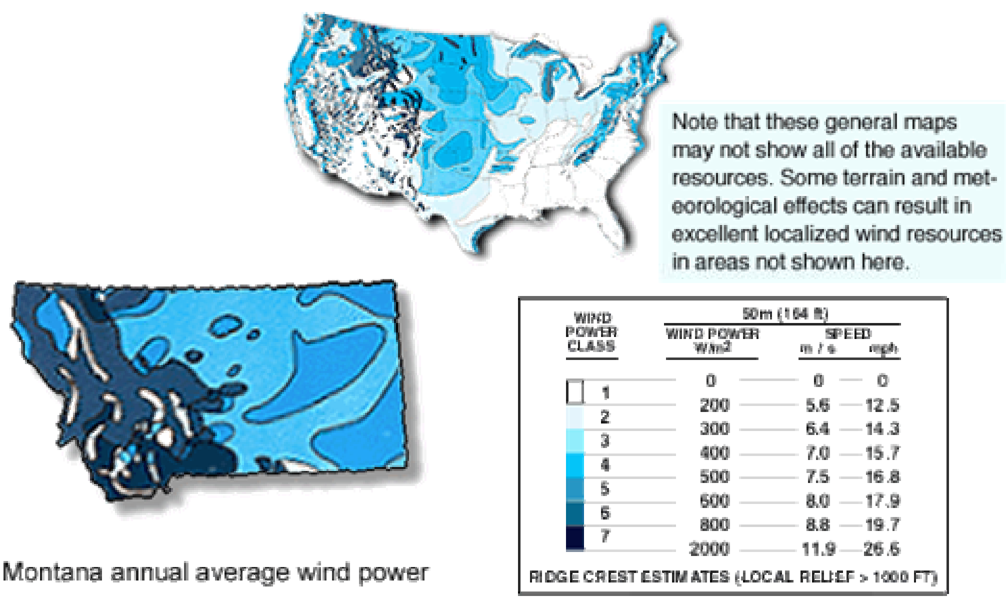
Fixed, investment-related costs are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs to approximately $750 to 1,000/kW. Wind power plants incur no fuel costs, however, and their maintenance costs have also declined with improved designs. The U.S. Department of Energy (DOE) Energy Information Administration (EIA) projects the levelized cost (the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments; costs are levelized in real dollars, i.e., adjusted to remove the impact of inflation) of wind power to be approximately $50.6/mWh (see Table 2-1).

Due to the intermittent nature of wind, a wind power plant's economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of a wind turbine's productivity. Estimates of capacity factors range from 26% to 36%.

FIGURE 2-1

Annual Average Wind Power in Montana

Source: U.S. DOE EERE State Energy Alternatives Website (Ref. 1)



Another major issue regarding wind intermittence is that wind power can offer energy, but not on-demand capacity. Even at the best sites, there are times when the wind does not blow sufficiently and no electricity is generated. Related to intermittence is wind's unpredictable nature. Weather forecasting has improved over the past several decades, so wind power plant operators can predict, to some extent, what their output will be by the hour. However, that ability is imperfect at best. Therefore, wind power cannot always be reliably dispatched at the time it is needed.

Good wind resource areas with accessibility to nearby transmission lines do exist; however, it is more common that wind resources are located some distance from adequate transmission lines. Larger wind developments (several hundred megawatts) are more likely to invest in transmission infrastructure.

Environmental Compatibility

While wind power has no air emissions or water use, it does have other impacts on the environment. These are visual obstruction, bird kills, and noise pollution. Mitigation measures are frequently taken to resolve most of these issues.

Air

There are no direct air emissions related to the installation of a wind farm. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators.

Water

There would be no major water discharge issues. A stormwater construction permit and management plan would be required for construction activities.

Footprint

A 250 mW wind farm would require approximately 72 square miles (46,000 acres) of area based on an average power output of 3.47 mW/square mile for wind power class 4 resources. As discussed previously, most of the land would be available for other uses such as agricultural production.

General Permitability

The primary obstacle in permitting large wind farms would be land issues, aesthetics, and public acceptance. Bird strikes can be a significant issue in areas of high avian use, such as major flyways. In general, environmental issues can typically be addressed to allow the development of a properly sited large-scale wind farm.

Southern Montana Electric G&T

SME currently receives a portion of the energy output from a large wind farm through it's contract with WAPA. This 5 mW source is available to the customers of the member cooperatives through SME.

The general recommendation for installed wind capacity on a utility system is 3 percent of load. Wind capacity above the 3 percent level can cause stability problems on the utility system resulting in the need for additional system infrastructure, such as static var compensators, capacitor banks or backup generation. For SME, the 3 percent level would represent a practical limit of approximately 5 mW of installed wind capacity. SME will evaluate options to install wind capacity on the SME system up to the 5 mW level.

Capable of Fulfilling Purpose and Need

Wind power cannot fulfill the need for 250 mW of highly reliable base load capacity. Wind power production is intermittent with an average annual capacity factor of 25 to 35 percent, depending on location.

The list of Montana Qualified Wind Facilities (Table 2-2) indicates that wind farm projects are not viewed as large, base load projects.

TABLE 2-2

Montana Qualified Wind Facilities

Facility Location	Facility Owner	Installed kW
	Wind Facilities	
Big Timber	Big Timber Wind Installations	4.5
Helena	Bill and Bonita Ikard	3.2
Great Falls	Bill Ecklund	10.0
Racetrack	Bill Schubert	100.0
	BLACKFEET RESERVATION	10.0
Great Falls	Bob Sechena	10.0
Butte	Dan O'Keefe	10.0
Sand Coulee	Dana Rossmiller	3.2
Great Falls	David Clark	65.0
LIVINGSTON	HEALOW #2	10.0
Stanford	Jess Alger	10.0
Joliet	Joliet Wind Installation	3.2
Great Falls	Ken Thorton	10.0
Butte	Luella O'Keefe	50.0
Luzenac	Luzenac Wind Installation	65.0
LIVINGSTON	MISSION CREEK	10.0
NORRIS	RICE RIDGE RENEWABLE ENERGY PARK	10.0
Butte	Shawn Hunter	10.0
Great Falls	Steve Benjamin	0.9
White Sulphur Springs	Steve Hicks	1.0
Three Forks	Three Forks Wind Installation	10.0
Cascade	Tom and Laurie Gilleon	3.2
White Sulphur Springs	White Sulphur Springs Wind Installation	10.0
Whitehall	Whitehall Wind Installation	0.0

Source: https://www.eere.energy.gov/state_energy/opfacbytech.cfm?state=mt

2.2.2 Solar

Overview

The sun is a direct source of energy. Using renewable energy technologies can convert that solar energy into electricity. However, solar energy varies by location and by the time of year. Solar resources are expressed in watt-hours per square meter per day (Wh/m^2/day). This is roughly a measure of how much energy falls on a square yard over the course of an average day.

Collectors that focus the sun (like a magnifying glass) can reach high temperatures and efficiencies. These are called solar concentrators. Typically, these collectors are controlled by a tracker, which positions the collector so that they always face the sun directly. Because these collectors focus the sun's rays, they only use the direct rays coming straight from the sun.

Other solar collectors consist of simply flat panels that can be mounted on a roof or on the ground. Called flat-plate collectors, these are typically fixed in a tilted position correlated to the latitude of the location. This allows the collector to best capture the sun. These collectors can use both the direct rays from the sun and reflected light that comes through a cloud or off the ground. Because they use all available sunlight, flat-plate collectors are the best choice for many northern states.

Solar resources are greatest in the middle of the day - the same time that utility customers have the highest demand, especially during the summer months.

Commercially Available

Solar concentrators and flat-plate collector types are both used in each of the solar-based technologies - PV and solar thermal.

The largest usage of PV has been in the off-grid market, which takes advantage of PV's ability to be a complete stand-alone electrical system. Telecommunications and transportation construction signage are the two largest segments of the off-grid market. Most of the off-grid market is due to remote locations and inaccessibility to the utility grid of applications, such as water pumping and highway lighting.

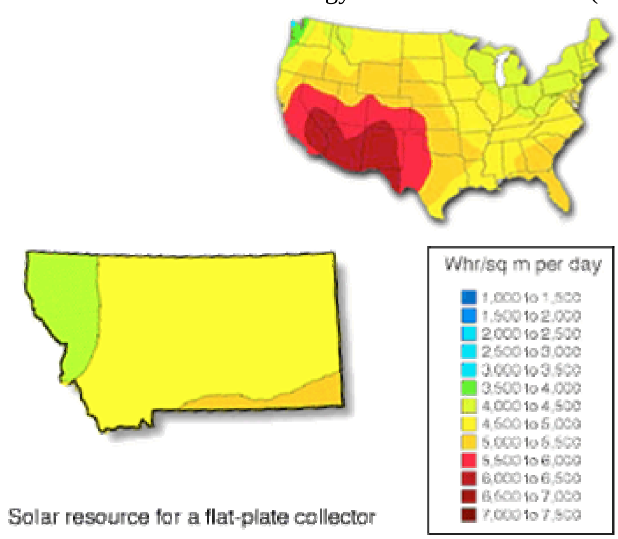
Technical Feasibility

Flat-Plate Collector

Flat-plate solar systems are flat panels that collect sunlight and convert it to either electricity or heat. These technologies include PV a flat-plate collector that is installed in a tilted position, for example, on a roof. A general rule of thumb is that a flat-plate collector gets the most sun if it is tilted toward the south at an angle equal to the latitude of the location.

As the map for flat-plate collectors shows (Figure 2-2), Montana has a useful resource throughout the state. Because of their simplicity, flat-plate collectors are often used for residential and commercial building applications. They can also be used in large arrays for utility applications.

Figure 2-2
Solar Resources for a Flat-Plate Collector in Montana
Source: U.S. DOE EERE State Energy Alternatives Website (Ref. 1)



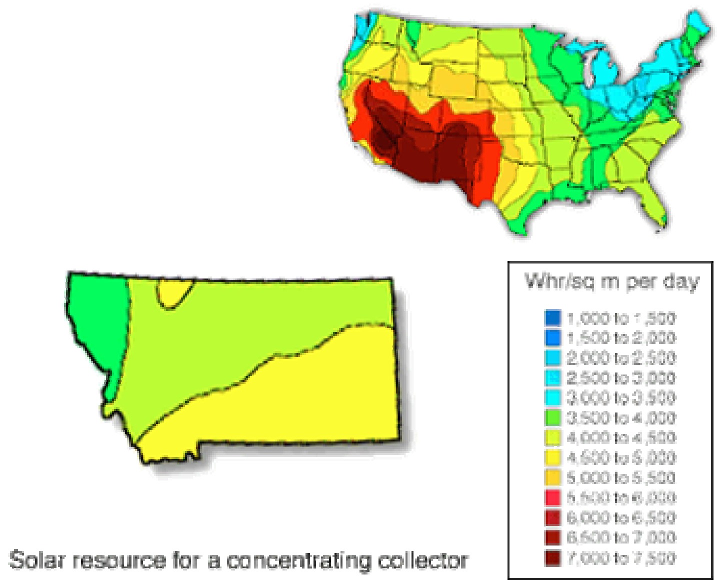
Solar Concentrator

Solar concentrators are typically mounted on tracking systems in order to face the sun continuously. This allows these collectors to capture the maximum amount of direct solar rays. The solar resource for concentrators varies much more across the United States than the flat-plate solar resource. Most northern states cannot use solar concentrators effectively, but this resource is even greater than the flat-plate resource in some areas of the southwestern United States.

The map (Figure 2-3) shows that, for concentrating collectors, Montana is considered a marginal resource. Although certain technologies may work in specific applications, most concentrating collectors are not effective with this resource. Because these systems require tracking mechanisms, solar concentrators are generally used for large-scale applications such as utility or industrial use. But they can also be used in small-scale applications, including remote power applications.

Figure 2-3

Solar Resources for a Concentrating Collector in Montana
Source: U.S. DOE EERE State Energy Alternatives website (Ref. 1)



Cost-Effectiveness

Fixed, investment-related charges are the largest component of solar-based electricity costs. The DOE Energy Information Administration projects the capital cost component of the levelized cost of solar power to be approximately $350/mWh for PV and $105/mWh for thermal solar. Solar power units incur no fuel costs. Maintenance costs are low for PV systems, however, maintenance costs are high for thermal solar applications.

Due to the intermittent nature of solar power, economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of solar power productivity. Estimates of capacity factors range from 20 percent to 35 percent.

Another major issue regarding solar power intermittence is that solar power can offer energy, but not on-demand capacity. Related to intermittence is solar power's unpredictable nature due to the weather.

Environmental Compatibility

In general, solar resources have relatively less impact on the environment as compared to other generation technologies, with the possible exceptions of aesthetics and the large area required for the facilities.

Air

There are no major direct air emissions related to the installation of a solar facility. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators.

Water

There would be no major water discharge issues. A stormwater construction permit and management plan will be required for construction activities.

Footprint

A 250 mW PV solar farm in the best area of Montana for solar power would require approximately 310 acres.

General Permitability

The primary obstacles in permitting a large solar installation would be land issues, aesthetics, and the public communication process. The use of other resources and emission would likely not be major permitability issues.

Southern Montana Electric G&T

SME is not currently pursuing any solar energy projects. These projects are not seen as being commercially viable within the SME system.

Capable of Fulfilling Purpose and Need

Solar power cannot fulfill the need for 250 mW of highly reliable base load capacity within the SME service area. Montana has a marginal solar resource and solar power production in the SME service area would be intermittent with an average annual capacity factor of 20 to 35 percent.

The list of Montana Qualified Solar Facilities (Table 2-3) indicates that solar facilities are not viewed as large, base load projects. There are two projects which are listed below with a larger size than the average shown.

Table 2-3

Montana Qualified Solar Facilities

Facility Type	Facility Location	Technology	Installed kW
Solar Facilities			
Photovoltaic	Average of 79 Projects	Solar	2.1
Photovoltaic	Missoula	Solar	15.0
Photovoltaic	Victor	Solar	58.2

Source: https://www.eere.energy.gov/state_energy/opfacbytech.cfm?state=mt

2.2.3 Hydroelectric

Overview

Flowing water creates energy that can be captured and turned into electricity. This is called hydroelectric power or hydropower.

The most common type of hydroelectric power plant uses a dam on a river to store water in a reservoir or a run of the river approach, which does not result in the construction of a large reservoir. Water released from the reservoir flows through a turbine, which in turn activates a generator to produce electricity. Another form of hydroelectric power does not require a large dam but instead uses a small canal to channel the river water through a turbine.

Another type of hydroelectric power plant, referred to as a pumped storage plant, has the capacity to store energy. The power is sent from a power grid into the electric generators. The generators then turn the turbines backward, which causes the turbines to pump water from a river or lower reservoir to an upper reservoir, where the energy is stored. To use the energy, the water is released from the upper reservoir back down into the river or lower reservoir. This turns the turbines forward, activating the generators to produce electricity.

Commercially Available

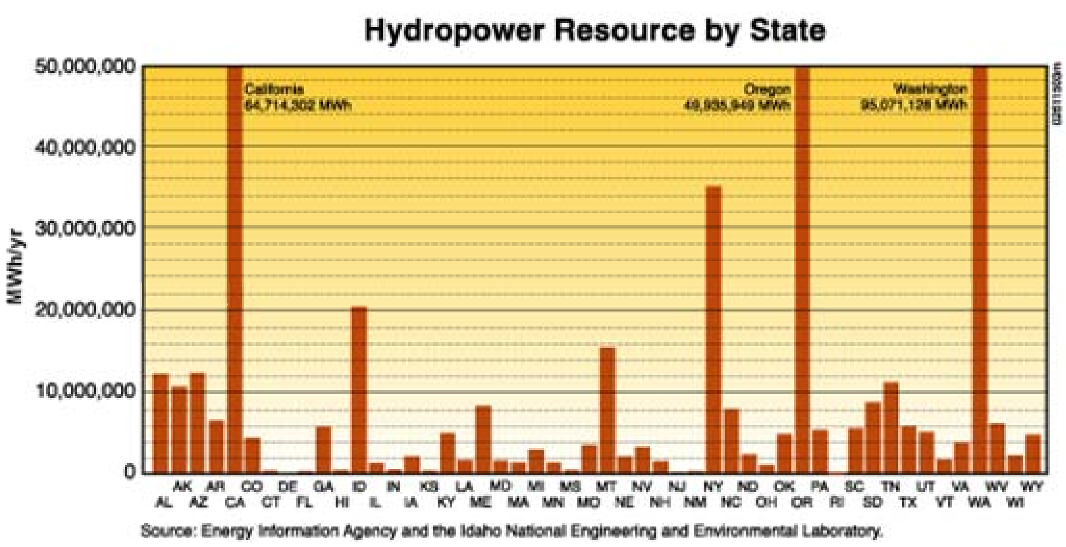
Hydroelectric power is available commercially and is responsible for a significant portion of the generation capacity in various regions of the United States and abroad.

Technical Feasibility

The amount of hydropower resource varies widely among states. To have a useable hydropower resource, there must be both a large volume of flowing water and a change in elevation.

Montana has relatively low hydropower resources as a percentage of each state's electricity generation. Montana could produce an estimated 15,648,736 mWh of electricity annually from hydropower (see Figure 2-4 below). This would be equivalent to approximately 48,230 mW of installed capacity assuming a 37 percent average annual capacity factor.

Figure 2-4
Hydropower Resource by State



The chart above (Figure 2-4) shows the overall likely potential hydropower resource by state. This includes both current hydropower generation as well as an estimate of potential additional resources. This estimate factored in the many legal, social, and environmental constraints on hydropower development.

Cost-Effectiveness

Fixed, investment-related charges are the largest component of hydroelectric power plant costs. The DOE's Idaho National Engineering and Environmental Laboratory (INEEL) reports hydropower capital costs to be $1,700 to $2,300/kW. Operating and maintenance costs are low for hydropower. The total levelized cost of hydropower is projected to be approximately $24/mWh (see Table 2-1).

Due to the seasonal nature of hydropower, the average annual capacity factor for most facilities is approximately 40 to 50 percent. Another major issue regarding hydropower is its year-to-year unpredictable nature due to annual rainfall variability.

Environmental Compatibility

Environmental impacts would vary dependent on the type and number of hydroelectric projects proposed: run of river, reservoir storage, or pumped storage. There would be minimal impacts in terms of air emissions, wastewater discharges, or solid waste/hazardous waste generation. The major impacts would be to the aquatic environment, alteration of river flows, land use alternations, and construction of reservoirs and structures.

Air

There are no major direct air emissions related to the installation of hydroelectric resources. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/ natural gas emergency generators.

Water

While there would be no major water discharge issues compared with typical thermal power plants, the construction of an impoundment or reservoir could have various adverse impacts on water quality, wetlands, flooding of uplands, and aquatic biota. A stormwater construction permit and management plan would be required for construction activities and ongoing operation. A Spill Prevention Control and Countermeasures (SPCC) plan may be required depending on the quantity of lubricating oils, transformer oils, and emergency generator fuels onsite.

Footprint

Because of the lack of significant topographic relief in south central and southwestern Montana, hydroelectric resources capable of providing 350 mW of generation would require numerous small hydroelectric facilities.

General Permitability

The permitting of a new hydroelectric facility is typically a complex and time-consuming process requiring multiple federal and state permits and approvals. Hydroelectric facilities are regulated by the Federal Energy Regulatory Commission (FERC). In addition to the development and approval of a number of detailed resource reports, approval under the National Environmental Policy Act (NEPA) through the preparation of an Environmental Impact Statement (EIS) would likely be required. Other federal permits such as a Section 404 dredge and fill permit and Section 10 water quality certification would also be required. Various state permits through the Montana Department of Natural Resources and the Public Service Commission of Montana would also be required. Development of hydroelectric facility can experience significant public and agency opposition.

Southern Montana Electric G&T

SME currently has 150 mW of hydropower generation capacity supplied by various projects. Due to the significant environmental issues associated with the development of new hydroelectric generation and limited resource availability, SME does not have current plans to install hydroelectric generation capacity.

Capable of Fulfilling Purpose and Need

Given the limited resources available for development of hydropower in Montana, it is unlikely that this technology could fulfill the need for 250 mW of highly reliable base load capacity. Hydroelectric power production is seasonal with an average annual capacity factor of 40 to 50 percent, depending on year-to-year rainfall levels.

The list of Montana Qualified Hydro Facilities (Table 2-3) indicates that hydro facilities installed in Montana vary in size from very small to large base load projects.

Table 2-4
Montana Qualified Hydro Facilities

Type	Owner	Project Name	Capacity kW
Hydro	SIEVERS, JAMES	BARNEY CREEK	68.0
Hydro	FLATHEAD ELECTRIC COOPERATIVE	BIG FORK	4,150.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	BLACK EAGLE	16,800.0
Hydro	CSK TRIBES [BOULDER CREEK-HYD]	BOULDER CREEK	350.0
Hydro	MONTANA-DNRC [STATE OF]	BROADWATER	9,660.0
Hydro	BUREAU OF RECLAMATION	CANYON FERRY	50,010.0
Hydro	SIEVERS, JAMES	CASCADE CREEK	75.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	COCHRANE	48,000.0
Hydro	USCE-MISSOURI RIVER DISTRICT	FORT PECK	185,250.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	HAUSER LAKE	17,000.0
Hydro	USBIA-FLATHEAD POWER DIVISION	HELLROARING HYDRO	360.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	HOLTER	38,400.0
Hydro	BUREAU OF RECLAMATION	HUNGRY HORSE	428,000.0
Hydro	JENNI HYDRO	JENNI HYDRO	240.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	KERR	168,000.0
Hydro	NORTHERN LIGHTS INC.	LAKE CREEK	4,500.0
Hydro	USCE-NORTH PACIFIC DIVISION	LIBBY	525,000.0
Hydro	BOULDER HYDRO LIMITED PARTNERSHIP	LITTLE GOLD CREEK	450.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	MADISON	9,000.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	MILLTOWN	3,040.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	MORONY	45,000.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	MYSTIC LAKE	12,000.0

Type	Owner	Project Name	Capacity kW
Hydro	BINGHAM ENGINEERING ET. AL. (OHS INC.)	NORTH WILLOW CREEK	400.0
Hydro	AVISTA CORP.	NOXON RAPIDS	466,200.0
Hydro	TOWN OF PHILIPSBURG	PHILIPSBURG WATER	200.0
Hydro	BINGHAM ENGINEERING ET. AL. (CARTER HYDRO LIMITED PARTNERSHIP)	PINE CREEK	373.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	RAINBOW MT	35,600.0
Hydro	ROSS CREEK HYDRO	ROSS CREEK	450.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	RYAN	48,000.0
Hydro	HYDRODYNAMICS INC.	SOUTH DRY CREEK	2,000.0
Hydro	POTOSI GENERATING STATION	SOUTH WILLOW CREEK	300.0
Hydro	HYDRODYNAMICS STRAWBERRY CREEK (SOUTH DRY CREEK PARTNERSHIP)	STRAWBERRY CREEK	275.0
Hydro	PP&L MONTANA LLC (PP&L GLOBAL RESOURCES INC.)	THOMPSON FALLS	70,000.0
Hydro	CITY OF WHITEFISH	WHITEFISH RESERVOIR	190.0
Hydro	BINGHAM ENGINEERING ET. AL. (WISCONSIN CREEK LIMITED PARTNERSHIP)	WISCONSIN-NOBLE	500.0
Hydro	BUREAU OF RECLAMATION	YELLOWTAIL	250,000.0

Source: https://www.eere.energy.gov/state_energy/opfacbytech.cfm?state=mt

2.2.4 Geothermal

Overview

Geothermal energy is contained in underground reservoirs of steam, hot water, and hot dry rocks. Electric generating facilities utilize hot water or steam extracted from geothermal reservoirs in the Earth's crust to drive steam turbine generators to produce electricity. Moderate-to-low temperature geothermal resources are used for direct-use applications such as district and space heating. Lower temperature, shallow ground, geothermal resources are used by geothermal heat pumps to heat and cool buildings. Hence, the only geothermal resources that may be considered to generate power are the high temperature sources.

Commercially Available

Producing electricity from geothermal resources involves a mature technology. The time from which a site is confirmed as having sufficient water or steam at temperatures high enough to drive turbines (using either a binary or flash system) to the time a facility can produce electricity is typically less than 3 years. However, due to the remote locations of many geothermal resources, the cost of transmission may make the venture more expensive than a facility that is closer to an identified interconnection point.

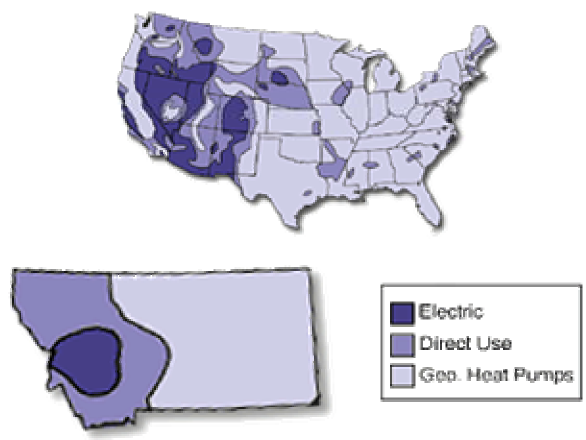
About 8,000 mW of geothermal electricity are currently produced around the world, including about 2,200 mW of capacity in the United States. All of the geothermal power in the United States is generated in California, Nevada, Utah, and Hawaii, with California accounting for over 90 percent of installed capacity. A considerable amount of the power (1,137 mW) is generated at the Geysers in northern California. The Geysers is a fairly unusual (and ideal) resource because its wells produce virtually pure steam with no water carry over.

Technical Feasibility

Two types of geothermal resources are being tapped commercially: hydrothermal fluid resources and earth energy. Hydrothermal fluid resources which are reservoirs of steam or very hot water, are well suited for electricity generation. Earth energy, the heat contained in soil and rocks at shallow depths, is excellent for direct use and geothermal heat pumps but not as a source of electric power generation.

As indicated on the map (Figure 2-5), Montana has low to moderate temperature resources that could be tapped for direct heat or for geothermal heat pumps. However, electric generation is not possible with these resources. Therefore, geothermal electric power generation is not technically feasible in this area.

Figure 2-5
Geothermal Resources in Montana
Source: U.S. DOE EERE State Energy Alternatives website (Ref. 1)



Montana geothermal resource

Cost-Effectiveness

Geothermal electric power typically ranges from \$50 to \$80/mWh, and technology improvements are steadily lowering this cost range.

Environmental Compatibility

Geothermal energy is generally one of the cleaner forms of energy available for commercial applications. Small direct heat resources generally have minimal air and water emissions. Large geothermal resources used for electrical generation have had issues with air emissions (primarily caused by the release of hydrogen sulfide [H_2S]) and water discharges and would need additional controls to minimize emissions. The high flow rates of steam and water from geothermal wells can result in the precipitation of various compounds on the steam generating and turbine equipment. These precipitation forms are primarily silica. Frequent cleaning of the equipment would result in land disposal of precipitates.

Air

The primary air pollutants of concern with geothermal resources are H_2S, ammonia (NH_3), and methane (CH_4). New designs are able to minimize emissions within the process and with the use of add-on emissions control equipment. Other minor sources of emissions include particulates from the process cooling tower and those associated with support equipment such as diesel/natural gas emergency generators.

Water

Depending on the quality of the water used in the geothermal process, there may be a need for an industrial wastewater treatment permit and pre-treatment. Stormwater and SPCC plans will be required.

Footprint

Land use for geothermal resources is normally small compared to fossil energy resources. A 20 mW geothermal power plant would require approximately 3 acres. Therefore, 13 of these plants having a total output of 250 mW would require a total area of approximately 39 acres.

General Permitability

Based on a good process design, there is a high probability that the necessary environmental permits and approvals could be obtained in a reasonable time.

Southern Montana Electric G&T

One of SME's member cooperatives currently provides incentives to install geothermal heat pumps. SME does not view geothermal generating facilities as technically or financially viable within its system.

Capable of Fulfilling Purpose and Need

Geothermal electric power cannot fulfill the need for 250 mW of highly reliable base load capacity within the SME service area due to the fact that commercial geothermal resources for the generation of electric power are not available.

2.3 Renewable Combustible Energy Resources

The renewable combustible energy resources evaluated in this section are biomass, biogas, and municipal solid waste (MSW). The electric power cost projections for these energy technologies are shown in Table 2-4.

Table 2-5
Electric Power Cost Projections for Renewable Combustible Energy Resources
Levelized Costs for New Utility Generating Plants in NWPP Region

	Levelized Costs ($/mWh)		
Cost Component	**Biomass**	**Biogas**	**Municipal Solid Waste (MSW)**
Capital	N/A	37.0	32.8
Fixed O&M	N/A	6.6	38.9
Variable/Fuel	N/A	3.0	13.0
Total	90.0	46.5	84.8

Source for Biomass Costs: U.S. Department of Energy (DOE) Energy Efficiency and Renewable Energy (EERE) State Energy Information - Biomass Power Technology website:(http://www.eere.energy.gov/state_energyttechnology_overview.cfm?techid=3)

Source for Biogas Costs: U.S. DOE Energy Information Administration (EIA) Annual Energy 2003 Outlook Reference Case. Based on the National Energy Modeling System (NEMS).

$/MWh - dollars per megawatt hour

0&M - operations and maintenance

2.3.1 Biomass

Overview

For heating applications or electricity generation, biomass can be directly burned in its solid form, or first converted into liquid or gaseous fuels by off-stoichiometric thermal decomposition. Biomass power technologies convert renewable biomass fuels into heat and electricity using modern boilers, gasifiers, turbines, generators, fuel cells, and other methods.

Biomass resource supply includes the use of five general categories of biomass: urban residues, mill residues, forest residues, agricultural residues, and energy crops. Of these potential biomass supplies and the quantities cited below, most forest residues, agricultural residues, and energy crops are not presently economic for energy use. New tax credits or incentives, increased monetary valuation of environmental benefits, or sustained high prices for fossil fuels could make these fuel sources more economic in the future. In addition, forest fires in the past several years in western states have generated increased stimulus to initiate forest thinning programs. Several biomass plants are being proposed in the west to use forest thinnings as a major fuel source.

Wood is the most commonly used biomass fuel for heat and power and is an available biomass resource in Montana. The most economic sources of wood fuels are usually urban residues and mill residues. Urban residues used for power generation consist mainly of chips and grindings of clean, non-hazardous wood from construction activities, woody yard and right-of-way trimmings, and discarded wood products such as waste pallets and crates. Local governments can encourage segregation of clean wood from other forms of municipal waste to help ensure its re-use for mulch, energy, and other markets. Using clean and segregated biomass materials for electricity generation recovers their energy value while avoiding landfill disposal. Development of power resources using urban residues would require coordination with municipalities to develop programs to collect and segregate the waste material and to arrange for its transport to the generating facilities.

Mill residues, such as sawdust, bark, wood scraps, and sludge from paper, lumber, and furniture manufacturing operations are typically very clean and can be used as fuel by a wide range of biomass energy systems. These forest industries are available in Montana, and offer potential fuel sources for power generation. However, these waste materials are often burned in boilers at the plants to produce thermal and/or electric power to run the mills.

Forest residues include underutilized logging residues, imperfect commercial trees, dead wood, and other non-commercial trees that need to be thinned from crowded, unhealthy, fire-prone forests. Because of their sparseness and remote location, these residues are usually more expensive to recover than urban and mill residues.

Agricultural residues are the biomass materials remaining after harvesting agricultural crops. These residues include wheat straw, corn stover (leaves, stalks, and cobs), orchard trimmings, rice straw and husks, and bagasse (sugar cane residue). The agricultural nature of much of Montana suggests that these may be a sparse but yet a viable resource within the state. Due to the high costs for recovering most agricultural residues, they are not yet widely used for energy purposes; however, they can offer a sizeable biomass resource if supply infrastructures are developed to economically recover and deliver them to energy facilities.

Energy crops are crops developed and grown specifically for fuel. These crops are carefully selected to be fast growing, drought and pest resistant, and readily harvested alternative crops. Energy crops include fast-growing trees, shrubs, and grasses, such as hybrid poplars, hybrid willows, and switchgrass, respectively. In addition to environmental benefits, energy crops can provide income benefits for farmers and rural land owners.

Commercially Available

Generating electricity from biomass residues is a proven and commercially available technology. Although many people envision substantial increases in biomass power for the future with "energy crop" plantations forming a primary supply base, this is not feasible in the near term. Presently, "closed-loop" (i.e., sustainably supplied) biomass power projects are at the research and demonstration phase.

Technical Feasibility

Almost all industrial firms that generate biomass-based electricity do so to achieve multiple objectives. First, most of these firms are producing biomass-related products and have waste streams (e.g., pulping liquor) available as (nearly) free fuel. This makes the cost of self-generation cheaper in many cases than purchasing electricity. Second, using waste to generate electricity also solves otherwise substantial waste disposal problems. Thus, the net cost of generation is much lower to the forest products industry than it would be if its generating facilities were used only to produce electricity, because a sizable waste disposal cost is being avoided. The use of waste-based fuel by some industrial generators to reduce waste disposal costs while simultaneously providing power is an example of synergy among industrial production, environmental concerns, and energy production.

Although the increased availability of forest understorey for fuel would represent an increase in the biomass resource base, any sizable short- to mid-term increase in commercially viable resources is not feasible. Trees require 20 to 40 years to reach full maturity, and while crops such as switchgrass and alfalfa can be grown quickly, the infrastructure for utilizing them for energy is limited. Transportation costs can also be very high when compared to the overall cost of fuel for the fuel heat content recovered.

Finally, a major limitation on the use of wood for energy within the forest product industry is the fact that wood has a higher value for its primary end uses (e.g., paper, packaging, structural components, insulating materials, panels, composite materials, chemical feed stocks, mulch, and sanitary products) than for fuel. Using more wood for fuel would place upward pressure on the cost of primary products, unless additional forest resources are available near current costs. In addition to the potential for traditional forest product companies to participate in electric generation, the degree of success which nontraditional participants in the national fiber market will experience must be evaluated. The principal nontraditional participant would likely be an electric utility considering co-firing biomass with coal. Scenarios for large increases in biomass-based power generation usually assume that some fraction of this electricity will come from co-firing. About 15 percent of a co-firing fuel mix can be biomass in theory. In practice, workable proportions may be closer to 5 percent. At the utility sector level, this scenario might imply that a big increase in biomass electricity assumes participation by many buyers making relatively small, scheduled fiber purchases.

The viability of the utility co-firing scenario, at first glimpse, does not appear favorable. Forest product industries are usually located in close proximity to timber resources. In contrast, utility generating facilities are located according to a number of considerations: water availability, land acquisition capability and costs, environmental and safety issues, transmission and distribution costs, and proximity to population centers, among others. These considerations often do not put utility plants within an economically feasible range (generally 50 miles) of biomass resources; the amount of wood required to satisfy only 5% of fuel requirements is far too small to transport wood in a manner similar to that of coal. Thus, some utilities that might wish to co-fire wood are faced with difficulties accessing fuel resources in a cost-effective manner.

Cost-Effectiveness

The cost to generate electricity from biomass varies depending on the type of technology used, the size of the power plant, and the cost of the biomass fuel supply. In today's direct-fired biomass power plants, generation costs are about $90/mWh.

Currently, the most economically attractive technology for biomass is co-firing. Co-firing installations range in size from 1 mW to 30 mW of capacity.

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs-the preferred system has transportation distances less than 100 miles. The most economical conditions exist when the energy use is located at the site where biomass residues are generated (i.e., at a paper mill or a sawmill).

Environmental Compatibility

The primary issue with firing biomass is the control of air emissions. Co-firing of biomass fuels in a coal-fired boiler is advantageous from a renewable energy point of view and as an alternative to land disposal.

Air

Biomass used as 5 to 15 percent co-firing in a coal-fired boiler would have similar air emissions and control requirements as those for a conventional pulverized coal or circulating fluidized bed boiler discussed in later sections of this report. A 250 mW biomass only fired boiler would have estimated air emissions shown in Table 2-5. A biomass-fired boiler would have low emissions of sulfur dioxide, however emissions of nitrogen oxides, carbon monoxide, particulate matter, and hazardous air pollutants would typically be higher than conventional coal-fired boilers or natural gas turbines. However, it is likely that a well-designed biomass fired power plant with adequate controls would meet the applicable air quality regulatory requirements.

Table 2-6
Biomass Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)	Nitrogen Oxide (NO_x)	Carbon Monoxide (CO)	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPS)	Mercury (Hg)	GHGs
274	2409	6570	810	427	0.038	2,135,000

Notes:
' Based on 250 megawatts (mW) wood-fired boiler with low-NOx burners and fabric filter. Average fuel heating value of 6,500 British thermal units (Btu)/pound (lb).
[2] **GHGs stands for greenhouse gases.**

Water

A biomass-fired power plant would have similar water use requirements as a coal-fired facility. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at biomass-fired power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans may also be required.

Footprint

A 20 mW biomass facility would require approximately 10 acres. Therefore, 13 plants would be required to total output of 250 mW would require a total area of approximately 130 acres.

General Permitability

From an air emissions point of view, a 100 percent biomass-fired boiler is not advantageous compared to coal or natural gas options. Environmental permitting would be comparable to that required for a coal-fired unit.

Southern Montana Electric G&T

SME has investigated the possibility of biomass generation. The key issue for biomass facilities has been the location and stability of the fuel source. A 20 mW biomass facility using wood waste from pulp mills in Montana was considered but did not advance due to the location and uncertainties associated with the wood waste supply.

Capable of Fulfilling Purpose and Need

Biomass cannot fulfill the need for 250 mW of long-term, cost-effective, and competitive generation of base load capacity for the SME service area due to its higher levelized cost compared to a conventional pulverized coal-fired or circulating fluidized bed power plant.

2.3.2 Biogas

Overview

The same types of anaerobic bacteria that produce natural gas also produce methane rich biogas today. Anaerobic bacteria break down or "digest" organic material in a two step process. The first step is to utilize acid former bacteria to breakdown the volatile solids in a waste stream to fatty acids. The second stage of the process is environmentally sensitive to changes in temperature and pH and must be free of oxygen to produce "biogas" as a waste product. The anaerobic processes can be managed in a "digester" (an airtight tank) or a covered lagoon (a pond used to store manure) for waste treatment. The primary benefits of anaerobic digestion are nutrient recycling, waste treatment, and odor control. Except in very large systems, biogas production is considered a secondary benefit.

In most cases, the methane produced by the digester is well-concentrated. Because methane is the principal component of natural gas (usually on the range of about 75%), it is an excellent source of energy for use either in cogeneration on the electrical grid or simply for fueling boilers at the wastewater treatment plant.

The methane captured from an anaerobic digester will naturally contain some impurities, chiefly sulfur, which should be scrubbed prior to pressurization and combustion. Anaerobic digesters are used in municipal wastewater treatment plants and on large farm, dairy, and ranch operations for disposal of animal waste.

Landfill biogas (LFG) is created when organic waste in a landfill naturally decomposes. This gas consists of about 50 percent methane, about 50 percent carbon dioxide, and a small amount of non-methane organic compounds. Instead of allowing LFG to escape into the air, it can be captured, converted, and used as an energy source. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and it helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change.

The various types of biogas can be collected and used as a fuel source to generate electricity using conventional generating technology.

Commercially Available

Production of electric power from both digester gas and landfill gas has been demonstrated commercially for many years.

Technical Feasibility

Digester or landfill gas can be used as fuel in reciprocating engines or in gas turbines to generate electricity. A special carburetor is needed for a reciprocating engine because the typical biogas heating value of 500 to 650 British thermal units (Btu)/standard cubic feet (SCF) is significantly lower than the typical heating value of natural gas at 1,000 Btu/SCF.

Gas turbines also require modifications to the combustion chamber to allow use of the lower Btu content biogas.

Pretreatment of the digester or landfill gas is very important to the long-term maintainability and reliability of the engines or turbines. The gas is typically treated to remove hydrogen sulfide, siloxanes, moisture, and particulates prior to combustion.

The current U.S. Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) landfill and project database lists four landfill sites in Montana that have the potential for a landfill gas to electric power project. Two of the landfills are located within or close to the SME service territory. One is located in Bozeman (owned and operated by the City of Bozeman) which is near the service territory and the other is located in Great Falls (owned and operated by Montana Waste Systems) which is within the service territory. The other two landfill locations are located at Missoula and Kalispell which are considerable distances to the SME service area.

Cost-Effectiveness

The DOE Energy Information Administration projects the capital cost component of the levelized cost of biogas power to be approximately $37/mWh in 2009. The total levelized cost of biogas power is projected to be approximately $46/mWh (see Table 2-1).

Environmental Compatibility

There is an environmental benefit of using digester or landfill gas as a fuel in a turbine resource because biogas is a renewable resource. The primary environmental compatibility issue is with air emissions. There are no major water discharge or solid waste/ hazardous waste generation issues.

Air

The air emissions for a turbine firing digester or landfill gas are similar to a natural gas fired turbine. The use of Selective Catalytic Reduction (SCR) for nitrogen oxide (NO_x) control and catalytic oxidation for carbon monoxide (CO) control may be required.

Water

There would be no major water discharge issues. A stormwater construction permit and management plan will be needed for construction activities. An SPCC plan may be required based on the quantity of oils used and stored onsite.

Footprint

A 20 mW biogas facility would require approximately 3 acres. Therefore, 13 of these plants having a total output of 250 mW would require a total area of approximately 39 acres.

General Permitability

Environmental permitting would be fairly straight forward. Depending on the size of the resource, major source Prevention of Significant Deterioration (PSD) permitting may be required.

Southern Montana Electric G&T

SME has investigated the possibility of biogas generation. The key issue for biogas facilities has been the location and uncertainties of the fuel source.

Capable of Fulfilling Purpose and Need

Biogas power cannot fulfill the need for 250 mW of highly reliable base load capacity. The amount of digester gas and landfill gas resources is limited within the SME service area.

2.3.3 Municipal Solid Waste

Overview

Municipal Solid Waste (MSW) typically uses a Refuse Derived Fuel (RDF) technology in waste-to-energy facilities to combust trash, garbage, and other combustible refuse. The material is received in its “as discarded” form and subjected to segregation of some of the recyclables and shredding prior to being fed into the boilers for combustion. MSW provides energy for power production and at the same time provides waste volume reduction. The plants range upward to 90 mW in size using multiple boilers to provide steam to a single condensing steam turbine generator. There are also a number of mass burn units in operation that burn the MSW directly in its “as discarded” form with only the larger non-combustibles removed. Mass burn technology has largely given way to RDF in response to pressure to recycle materials and because the boilers designed to handle RDF are more economical to build.

The components of a typical RDF facility for MSW are discussed below:

- Refuse receiving area or tipping floor where trash trucks deposit refuse - A material handling process takes place in which cranes or tractors are used to mix the refuse and remove non-combustible items (such as large appliances) and certain recyclables. The refuse is then conveyed through a shredder and deposited into refuse feed hoppers, which feed the boilers.
- Combustion and steam generation system - RDF technologies include various types of combustors including water wall furnace, refractory furnace, rotary kiln furnace, water-cooled rotary combustor furnace, and controlled air furnace. The water wall furnace is the most common in use. Heat from the combustion process is used to generate steam. Steam is routed to a steam turbine generator converting thermal energy to mechanical energy. The steam turbine drives the generator to produce electricity. The steam is exhausted to the condenser, which condenses the steam through cooling by means of cooling or circulating water sourced from either a cooling tower or waterway in the case of once-through cooling.
- Flue Gas Treatment - MSW combustion generates solid wastes and air pollutants. Residues produced include bottom ash, unburnable organic waste, and fly ash. Fly ash is captured through the use of a fabric filter or bag house. NOx and sulfur dioxide (SO2) are also produced and mitigated though the use of SCR and Flue Gas Desulphurization (FGD) downstream of the combustion process. The alkaline reagents used to capture SO2 also serve to neutralize other acid gases created during the combustion process.

There is the potential for the production of toxic trace metals such as lead, mercury, and beryllium during the combustion process. This can be controlled somewhat by source separation (small batteries are a source of mercury) and by use of selenium filters which are effective in the removal of mercury from flue gas. However, the potential exists to require special disposal precautions due to the presence of these materials in the solid waste. The production of dioxins from the combustion of plastics has been an emissions concern. Dioxin production is controlled by maintaining sufficiently high combustion temperatures in the furnace with supplemental fuel, if required, to incinerate them.

Commercially Available

MSW technology is available commercially, with operating facilities in many states.

Technical Feasibility

MSW technologies are currently used by municipalities and private industries in many locations in Europe and the United States. New technologies employing gasification of waste material followed by gas combustion to produce steam and power are also being developed.

Cost-Effectiveness

New MSW to energy plants are not currently cost competitive with conventional power generation technologies. The capital cost of an MSW power project is approximately $3,500 to $4,000/kW. The total levelized cost of MSW power is projected to be approximately $85/mWh (see Table 2-1). Typically MSW power plants become economical only when landfills for MSW disposal are not available near the collection area and hauling costs become excessive. The MSW power plants can command a tipping fee to offset the high cost of power production, but these need to be in the $50 to $60/ton range in order for the plant to be competitive. These conditions exist in high population density areas such as New York City. Except for small, localized areas, the potential for economical power to be generated in Montana from MSW does not exist.

Environmental Compatibility

The primary environmental benefit of a MSW electric-generation facility is the reduction of wastes that would ordinarily be sent to a landfill for disposal. The primary disadvantage is related to emissions of hazardous air pollutants (HAPs). This issue has made the permitting of MSW electric generation facilities a difficult process in many areas of the country and there is substantial public opposition to siting these facilities.

Air

Estimated air emissions from a 250 mW MSW electric-generation facility are shown in Table 2-6. Emissions of criteria air pollutants are comparable or lower than a coal-fired resource, however, the emissions of hazardous air pollutants including mercury, cadmium, and toxic organics are considerably higher.

Table 2-7
MSW Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)	Nitrogen Oxide (NO_x)	Carbon Monoxide (CO)	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPS)	Mercury (Hg)	GHGs
439	4,886	1911	132	54	0.29	2,668,000

Note:
Based on mass bum water wall combustor; 4,500 British thermal units (Btu)/pound (lb); 2,433,000 tons refuse derived fuel per year (RDF/yr); Lime Spray Dryer, Fabric Filter, and Selective Catalytic Reduction (at 80 percent control); AP-42 Section 2.1 emission factors.

Water

A MSW-fired power plant using mass burn technology would have similar water use requirements as a coal-fired facility. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at biomass-fired power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans will also be required.

Footprint

A 20 mW MSW electric-generation facility would require approximately 7 acres. Therefore, 13 of these plants with a total output of 250 mW would require a total area of approximately 91 acres.

General Permitability

Permitting of a large MSW electric-generation facility would be a long and complicated process. The public communication and hearing process would be extensive. The probability of obtaining a permit to operate is marginal. Significant public opposition can be generated against MSW-fired power plants that can significantly complicate and lengthen the overall permitting process.

Southern Montana Electric G&T

SME serves rural areas and does not have a municipal customer large enough to support a municipal solid waste-to-energy project.

Capable of Fulfilling Purpose and Need

MSW cannot fulfill the need for 250 mW of long-term, cost-effective, and competitive generation of base load capacity for the SME service area due to its higher levelized cost.

2.4 Non-Renewable Combustible Energy Resources

The non-renewable combustible energy resources evaluated in this section are natural gas combined cycle (NGCC), microturbines, pulverized coal (PC), circulating fluidized bed (CFB) coal, and IGCC coal. The electric power cost projections for these energy technologies are shown in Table 2-8 below.

Table 2-8
Electric Power Cost Projections for Non-Renewable Combustible Energy Resources
Levelized Costs for New 250 MW Power Plant (Microturbines @ 30 kW), 90 Percent Capacity Factor

	Levelized Costs ($/mWh)				
Cost Component	**Natural Gas Combined Cycle (NGCC)**	**Microtubines**	**Subcritical Pulverized Coal (PC) Powder River Basin (PRB) Coal**	**Circulating Fluidized Bed (CFB) Powder River Basin (PRB) Coal**	**Integrated Gasification Combined Cycle (IGCC) Bituminous Coal**
Capital	19.0	49.1	33.8	25.2	42.8
Fixed O&M	2.3	8.4	4.6	4.6	3.3
Variable / Fuel	41.0	55.7	11.7	12.8	19.8
Total Busbar Cost[1]	62.3	113.2	50.1[2]	42.6	65.9

Notes:
[1] Busbar Cost-wholesale cost to generate power at the plant.
[2] Reference #12, Table 21 for Advanced Coal plant.
$/mWh dollars per megawatt hour
O&M operations and maintenance

2.4.1 Natural Gas Combined Cycle

Overview

Combustion turbine generators (CTGs) are used for simple cycle and combined cycle applications. In simple cycle operation, gas turbines are operated alone, without any recovery of the energy in the hot exhaust gases. Simple cycle gas turbine generators are typically used for peaking or reserve utility power applications, which primarily are operated during the peak summer months (June through September) at less than a total of 2,000 hours per year. Simple cycle applications are rarely used in base load applications because of the lower heat rate efficiencies compared to a combined cycle configuration.

Combined cycle operation consists of one or more combustion turbine generators exhausting to one or more heat recovery steam generators (HRSGs). The resulting steam generated by the HRSGs is then used to power a steam turbine generator (STG).

There is a wide range of gas turbine size ranging from approximately 1 MW output up to "G" and "H" class machines which are rated at 240 MW and higher. Gas turbines for electric utility services generally range from a minimum of 20 MW for peaking service up to the largest machines for use in combined cycle mode.

Combustion Turbine Generators

There are two types of combustion gas turbines: heavy industrial "frame" machines and aero-derivative machines which are limited in maximum size to about 50 MW. In a combined cycle plant using frame machines, this provides for more steam, higher superheat temperatures and, therefore, more electrical output from the steam turbine.

Gas turbine powered plants are pre-assembled at the factory, skid or baseplate mounted, and shipped to the site along with other major components including the generator, cooling, lube oil, and electrical modules. Because of the pre-assembled modular approach, field erection hours are significantly reduced, particularly as compared to a coal-fueled plant.

Heat Recovery Steam Generators

HRSGs extract energy from the combustion turbine exhaust gases in order to produce steam. On larger systems, steam is produced at several pressures and temperatures to make the most efficient use of the energy available. Reheat cycles are incorporated to take advantage of the higher exhaust temperatures available on the larger advanced technology combustion turbines.

Steam Turbine Generator

The STG converts the energy produced by the HSRG in the form of steam into electrical energy. Larger STG units generally are pedestal mounted with the condenser located underneath the STG.

The condenser condenses the steam leaving the STG and collects the condensate for return to the de-aerator. Condensation is accomplished by dissipating the energy into cooling or circulating water piped to and from a cooling tower (or intake and discharge from a waterway in the case of once-through cooling). Alternatively, an air-cooled condenser may be used on a site that has lack of water availability, cooling tower blowdown disposal problems, cooling tower freeze-up, cooling tower vapor plume problems, or circulating water pollution restrictions (in the case of once-through cooling). Air-cooled condensers present a set of disadvantages: lower cycle efficiency, higher first cost, bigger site, higher noise levels, and higher operation costs.

Commercially Available

Natural gas combined cycle power plants are available commercially. Most new base load power plant facilities built in the United States in the past 10 years have used NGCC technology.

Technical Feasibility

NGCC plants have demonstrated high reliability and low maintenance costs.

Cost-Effectiveness

The capital cost component of the levelized cost of NGCC power is very low at approximately $12.5/mWh. However, the total levelized cost of NGCC power is projected to be relatively high at approximately $49.8/mWh(see Table 2-8).

Most of the power-generation cost for NGCC is from the variable/fuel cost at $35.9/mWh. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels.

Weather is the largest single factor affecting gas prices and the most unpredictable. Traditionally, demand for natural gas peaks in the coldest months, but with the nation's power increasingly being generated by natural gas, demand also spikes in summer, when companies place peaking plants on line to provide more power for cooling needs.

Environmental Compatibility

A natural gas combined cycle facility has lower criteria, HAP, and carbon dioxide (CO_2) emissions than a comparable coal-fired alternative. There are no major water discharge or solid waste/hazardous waste generation issues.

Air

Estimated air emissions for a 250 mW natural gas combined cycle resource are shown in Table 2-8. A major source PSD permit would be required. Current best available control technology (BACT) would require SCR for NO_x control and catalytic oxidation for CO control. There would also be particulate matter (PM_{10}) emissions from a cooling tower. There could also be other minor sources of air emissions from miscellaneous support equipment such as diesel/natural gas emergency generators and fire pumps.

Table 2-9
NGCC Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)	Nitrogen Oxide (NO_x)	Carbon Monoxide (CO)	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPS)	Mercury (Hg)	GHGs
30	87	131	58	9	-	963,000

Note:
Based on 250 megawatts (mW) Combined Cycle Turbine; 8,000 British thermal units (Btu)/gross kilowatt hours (kWh) heat rate; 90% NO_x removal with selective catalytic reduction (SCR); AP-42 Section 3.1 emission factors.

Water

A NGCC power plant using wet cooling would have similar but lower water use requirements as a coal-fired facility. In a typical combined cycle plant, approximately one-third of the total generation capacity comes from the steam cycle, two-thirds is generated directly by the combustion turbine/ generator equipment. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with coal-fired power plants, dry cooling or zero liquid discharge systems could be used at NGCC power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans will be required.

Footprint

A 250 mW natural gas combined cycle turbine facility would require approximately 25 acres.

General Permitability

Permitting of a NGCC power plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. However, based on the relatively low emissions compared to other alternatives, the application, review, and public comment processes would be fairly straight forward.

Southern Montana Electric G&T

The need for base load energy and the price volatility of natural gas were the deciding factors in SME's decision not to pursue additional natural gas fired units.

Capable of Fulfilling Purpose and Need

A NGCC power plant is not capable of fulfilling the purpose and need for SME because it is subject to highly variable natural gas fuel costs.

2.4.2 Microturbines

Overview

Microturbines are small electricity generators that burn gaseous and liquid fuels to create high-speed rotation that turns an electrical generator. Current microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment, and turbochargers, much of which was pursued by the automotive industry beginning in the 1950s. Microturbines entered field testing around 1997 and began initial commercial service in 2000.

The size range for microturbines commercially proven and currently available is from 30 to 70 kW, compared to conventional gas turbine sizes that range from approximately 1 to 240 MW. Microturbines operate at high speeds and may be used in simple cycle or cogeneration systems. They are able to operate on a variety of fuels, including natural gas, sour gas, landfill gas, anaerobic digester gas and diesel fuel/distillate heating oil. In resource recovery applications, they burn waste gases that would otherwise be flared.

Microturbines are ideally suited for distributed generation applications due to their small power output and space requirement, flexibility in connection methods, ability to be installed in parallel to serve larger loads, ability to provide stable and reliable power, and low emissions. Types of applications include stand-alone primary power, backup/standby power, peak shaving and primary power (grid parallel), primary power with grid as backup, resource recovery and cogeneration.

Commercially Available

Microturbines are currently operating in resource recovery operations at oil and gas production fields, wellheads, coal mines, landfills and WWTP digester gas operations, where byproduct gases serve as essentially free fuel. Reliable unattended operation is important since these locations may be remote from the grid. Target customers include financial services, data processing, telecommunications, office buildings and other commercial sectors that may experience costly downtime when electric service is lost from the grid.

Capstone and Ingersol Rand (IR) are currently the only commercial manufacturers providing microturbines for continuous operation in natural gas and resource recovery applications. Capstone Turbine Corporation, one of the world's leading manufacturers of microturbines, currently offers two (2) commercially available sizes of microturbines-the 30 kW and the 60 kW. IR currently offers a 70-kW turbocharged microturbine.

Technical Feasibility

Microturbine design life is estimated to be in the 40,000 to 80,000 hour range. However, while units have demonstrated reliability, they have not been in commercial service long enough to provide definitive data.

Cost-Effectiveness

Microturbine power plants are not currently cost competitive with conventional power-generation technologies. The capital cost of a microturbine unit is approximately $2,500/kW. The total levelized cost of microturbine power is projected to be approximately $113/mWh (see Table 2-8). Typically, microturbine units become economical for remote locations, when grid power is not available, and when low cost waste fuel is available.

Environmental Compatibility

The primary environmental compatibility issue is with air emissions. There are no major water discharge or solid waste/hazardous waste generation issues.

Air

The air emissions for a microturbine burning natural gas are similar to a combustion turbine without add-on controls on a lb/mWh basis. However, a typical combined cycle installation would have both SCR for NO_x control and catalytic oxidation for CO control. Thus, on a per mW basis, NO_X and CO emissions from a microturbine are substantially higher. Estimated air emissions for a 30 kW natural gas simple cycle unit are shown in Table 2-9.

Table 2-10
Microturbine Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)	Nitrogen Oxide (NO_x)	Carbon Monoxide (CO)	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPS)	Mercury (Hg)	GHGs
0.01	0.01	0.15	0.01	0.0	-	203

Notes; Based on 30 kW microturbine; 0.437 MMBtu/hr heat input; 80% capacity factor; Dry Low NO_x combustion; emission factors based on AP-42 Section 3.1 and EPA paper, *Technology Characterization: Microturbines,* March 2002.

Water

A small microturbine installation is self-contained. There are no water supply or wastewater discharge issues.

Footprint

A 30 kW natural gas simple cycle microturbine unit would require approximately 12 square feet of floor space, and a 70-kw microturbine would require approximately 24 square feet of floor space. It would require approximately 3,570 to 8,300 microturbines, based on the commercially size range of 30 to 70 kW each, to generate 250 MW of power. The total space requirement for 250 MW of microturbine installations would be approximately 85,700 to 100,000 square feet, or 1.9 to 2.3 acres.

General Permitability

Environmental permitting requirements would be dependent on the maximum number of microturbines to be installed at a specific location. A minor source air construction permit may be required. It is highly unlikely that PSD permitting would be required. Approximately 666 30-kW microturbines would have to be installed at a facility to require PSD significance levels (40 tons NO_x or SO_2, or 100 tons CO).

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SME is not pursuing microturbine projects due to cost and limited size.

Capable of Fulfilling Purpose and Need

Microturbine units cannot fulfill the need for 250 mW of long-term, cost-effective, and competitive generation of base load capacity for the SME service area due to its higher levelized cost compared to a conventional pulverized coal-fired power plant. Microturbines are not well suited for base load operations; they are typically used in remote locations burning waste gases where grid power is not available.

2.4.3 Pulverized Coal

Overview

Pulverized coal plants represent the most mature of technologies considered in this analysis. Coal plants, although having a high capital cost relative to some alternatives, have an advantage over other non-renewable combustible energy source technologies due to the relative low and stable cost of coal.

Modern pulverized coal plants generally range in size from 80 MW to 1,300 MW and can use coal from various sources. Coal is most often delivered by unit train to the site, although barges or trucks are also used. Many plants are situated adjacent to the coal source where coal delivery can be by conveyor.

Coal can have various characteristics with varying Btu heating values, sulfur content, and ash constituents. The source of coal and coal characteristics can have a significant effect on the plant design in terms of coal-handling facilities and types of pollution control equipment required.

Regardless of the source, the plant coal-handling system unloads the coal, stacks out the coal, reclaims the coal as required, and crushes the coal for storage in silos. Then the coal is fed from the silos to the pulverizers and blown into the steam generator. The steam generator mixes the pulverized coal with air, which is combusted, and in the process produces heat to generate steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

The steam generator produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash, NO_x, and SO_2. The pollution control equipment includes either a fabric filter (bag house) or electrostatic precipitator for particulate control (fly ash), SCR for removal of NO_x, and a FGD system for removal of SO_2. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulphurization. A limestone storage and handling system is a required design consideration with this system.

Coal plants produce several forms of liquid and solid waste. Liquid wastes include cooling tower blowdown, coal pile runoff, chemicals associated with water treatment, ash conveying water, and FGD wastewater. Solid wastes include bottom and fly ash and FGD solid wastes. Disposal of these wastes is a major factor is plant design and cost considerations.

Commercially Available

Pulverized coal is available commercially, with a long history of being the technology of choice for large base-load utility units.

Technical Feasibility

Pulverized coal has been used for large utility units for over 50 years. The technology has evolved in areas such as emissions and controls to improve its technical feasibility.

Cost-Effectiveness

The relatively low fuel cost for coal results in a low cost of electricity. Over half of the electricity generated in this country is generated by coal-fired units, almost all of it from PC units. Current fuel costs result in coal being the economical choice for large additions of new generation in areas with reasonable access to coal.

Environmental Compatibility

Environmental impacts associated with pulverized coal resources include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash.

Air

Estimated air emissions for a 250 MW pulverized coal resource are shown in Table 2-11. A major source PSD permit would be required. Current BACT would require low-NO_x burners and SCR for NO_x control, lime dry FGD or limestone/lime wet FGD for SO_2 control, and a fabric filter or electrostatic precipitator (ESP) for particulate control. There would also be PM_{10} emissions from cooling towers and coal, ash, and limestone or lime material handling operations. There could also be other sources of air emissions from miscellaneous support equipment such as diesel/natural gas emergency generators, fire pumps, and the installation of an auxiliary boiler. A case-by-case, maximum achievable control technology (MACT) analysis would be required for mercury, trace metals, organics, and acid gases.

Table 2-11
Pulverized Coal Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)[1]	Nitrogen Oxide (NO_x)[1]	Carbon Monoxide (CO)[1]	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPS)	Mercury (Hg)	GHGs
1330	887	1330	166	33	0.05	1,941,000

Note:
Based on pulverized coal boiler, Powder River Basin (PRB) coal 8,000 British thermal units (Btu)/pound; 9,000 Btu/gross kilowatt hours (kWh) heat rate; 1,108,700 tons/yr coal; lime spray dryer, fabric filter and selective catalytic reduction; AP 42 emissions factors; U.S. Department of Energy (DOE) Energy Information Agency (EIA) Carbon Dioxide (CO_2) factor of 1,970 lb/megawatt hours (mWh).

[1]These emissions values were extracted from resent air permits issued in the state of Montana and were found to be comparable with the AP42 emissions factors.

Water

Coal plants require a reliable long-term source of water. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with other generating technologies that utilize a steam cycle, dry cooling or zero liquid discharge systems are an option to reduce overall water consumption and discharge. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. Stormwater and SPCC plans will be required.

Footprint

A 250 mW pulverized coal facility would require approximately 90 to 160 acres.

General Permitability

Permitting of a pulverized coal plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit will be required. The permit application, agency review and follow-up, and public comment process can be extensive for a new coal-fired resource.

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SME is currently in the process of evaluating the option to add an additional 250 mW of base load coal-fired generation to its system. Because of the increase in base load generation on the SME system over the next 20 years (see section on Purpose and Need in this document), SME has identified the option of a 250 mW coal-fired generation to meet this growing demand.

Capable of Fulfilling Purpose and Need

Pulverized coal is capable of fulfilling SME's need for new generation in 2009 and beyond.

2.4.4 Circulating Fluidized Bed Coal

Overview

In the mid 1980s, an alternative to the standard PC fired plant emerged called CFB combustion. The fuel delivery system is similar, but somewhat simplified, to that of a pulverized coal unit but with a greater fuel cost advantage in that a wider range of fuels and lesser quality of fuel can be used (coal, coke, biomass, etc.). The bed material is composed of fuel, ash, sand, and sorbent (typically limestone). CFB units compete in the marketplace in sizes up to 300 mW with larger sizes available soon.

CFB combustion temperatures are significantly lower than a conventional boiler at 1,500 to 1,600 degrees Fahrenheit (°F) vs. 3,000°F which results in lower NO_x emissions and reduction of slagging and fouling characteristic of PC units. In contrast to a PC plant, sulfur dioxide is partially removed during the combustion process by adding limestone to the fluidized bed.

The plant fuel handling system unloads the fuel, stacks out the fuel, crushes or otherwise prepares the fuel for combustion, and reclaims the fuel as required. The fuel is usually fed into to the CFB by gravimetric feeders. In the CFB the fuel is combusted and in the process produces steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity.

The CFB produces combustion gases, which must be treated before exiting the exhaust stack to remove fly ash and sulfur dioxides. NO_x emissions can be mitigated through use of selective non-catalytic reduction (SNR) using ammonia injection, usually in the upper area of the combustor. The pollution control equipment external to the CFB includes either a fabric filter (bag house) or electrostatic precipitator for particulate control (fly ash), and a polishing FGD system for additional removal of sulfur dioxides to achieve similar levels to PC units. Limestone is required for the most common wet FGD process, limestone forced oxidation desulphurization, and also as sorbent for the fluidized bed. Another method is to re-circulate the fly ash and lime (remaining from the limestone desulphurization process) thru a hydration process. This hydrated material is re-injected into the inlet of the of the bag house for additional sulphur capture.

Similar to a PC plant, a CFB plant produces several forms of liquid and solid waste. Liquid wastes include cooling tower blowdown, chemicals associated with water treatment, ash conveying water, and FGD wastewater. Solid wastes include bed and fly ash and FGD solid wastes. As with PC fired units, disposal of these wastes is a major factor in plant design and cost considerations.

Commercially Available

The CFB technology is available commercially. The 300 mW unit size is the largest CFB units in operation.

Technical Feasibility

CFB power plants have demonstrated technical feasibility in commercial utility applications for about 20 years. The technology has evolved during that time to improve its technical feasibility.

Cost-Effectiveness

CFB units in the 300 mW size are cost-competitive with other technologies.

Environmental Compatibility

Environmental impacts associated with a CFB coal resource include air emissions, water/wastewater discharge issues, and solid waste disposal. Impacts are minimized by utilizing air pollution control equipment, wastewater pretreatment controls, and the potential reuse of ash. A CFB design does have the advantage of burning a wider range of fuels.

Air

Estimated air emissions for a 250 mW CFB resource are shown in Table 2-12. The air emissions exiting a CFB boiler (especially NO_x SO_2, and CO) are lower than a conventional pulverized coal boiler. A major source PSD permit will be required. Current BACT would require SNCR for NO_x control, finishing fuel gas scrubber (either wet or dry type) for SO_2 control, and a fabric filter or ESP for particulate control. There would also be PM_{10} emissions from cooling towers and coal, ash, and limestone material handling operations. There could also be other sources of air emissions from miscellaneous support equipment, such as diesel/natural gas emergency generators, fire pumps, and the installation of an auxiliary boiler. A case-by-case MACT analysis would be required for mercury, other trace metals in the coal, organics, and acid gases.

Table 2-12
CFB Coal Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)[1]	Nitrogen Oxide (NO_x)[1]	Carbon Monoxide (CO)[1]	Particulate Matter (PM_{10})[1]	Hazardous Air Pollutants (HAPS)[1]	Mercury (Hg)[2]	GHGs[3]
142	887	710	89	18	0.05	1,941,000

Note:
Based on circulating fluidized bed boiler; Powder River Basin (PRB) coal 8,000 British thermal units (Btu)/pound (lb); 9,000 Btu/gross kilowatt hours (kWh) heat rate; 1,108,700 tons/yr coal; limestone flash dryer absorber desulphurization, fabric filter and selective non-catalytic reduction;

[1] Information obtained from CFB boiler suppliers

[2] AP42 Emissions Factors

[3] U.S. Department of Energy (DOE) Energy Information Agency (EIA) Carbon Dioxide (CO2) factor of 1970 lb/megawatt hours (mWh).

Water

Coal plants require a reliable long-term source of water. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with other generating technologies that utilize a steam cycle, dry cooling or zero liquid discharge systems are an option to reduce overall water consumption and discharge. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. Stormwater and SPCC plans will be required.

Footprint

A 250 MW CFB facility would require approximately 90 to 160 acres.

General Permitability

Permitting of a CFB coal plant typically requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. The permit application, agency review and follow-up, and public comment process can be extensive for a new coal-fired resource.

Capable of Fulfilling Purpose and Need

The CFB technology is capable of fulfilling SME's need for new generation in 2009.

2.4.5 Integrated Gasification Combined Cycle Coal

Overview

Coal gasification for use in power generation reacts coal with steam and oxygen under high pressure and at high temperature to produce a gaseous mixture consisting primarily of hydrogen and carbon monoxide. The gaseous mixture requires cooling and cleanup to remove contaminants and pollutants to produce a synthesis gas suitable for use in the combustion turbine portion of a combined cycle unit. The combined cycle portion of the plant is similar to a conventional combined cycle. The most significant differences in the combined cycle are modifications to the combustion turbine to allow use of a 250 to 300 Btu/SCF gas and steam production via heat recovery from the formation of the raw gas in addition to the combustion turbine exhaust (HRSG). Specifics of a plant design are influenced by the gasification process, degree of heat recovery, and methods to clean up the gas.

Commercially Available

The current and near-term IGCC plants must be viewed as technically feasible, but not cost effective with low reliability which renders the technology to be economically attractive. The current IGCC plants are providing operational information about the technology, but fail to demonstrate the necessary cost of electricity to allow the technology to be available commercially in time to support SME's needs.

Technical Feasibility

IGCC has been demonstrated in a few commercial-scale facilities. A variety of coals have been gasified, the resulting gases have been processed to allow use in combustion turbines. However, the capital cost and performance in a number of areas have not been as attractive as planned. Some of the areas for which IGCC are noted include high-temperature heat recovery and hot gas cleanup. An important part of achieving an attractive heat rate is generation of high pressure and temperature steam from the high-temperature raw gas generated by gasifying coal. The temperature of the raw gas is dependent on the gasification process and the coal. Slagging type gasifiers, such as the Texaco process, typically generate gases in the 2500 to 2800°F range. These high-temperature gases containing corrosive compounds, such as H_2S. H_2S creates a very demanding environment for the components used in generation of high pressure and temperature steam. The reliable generation of steam under these conditions has not been demonstrated in a commercial application. Alternative technologies which do not recover the heat in the raw gas, such as direct quenching of the gas, result in lower efficiencies. It is also attractive from an efficiency perspective to provide clean gas to the combustion turbine at an elevated temperature without cooling and reheating, hence there is a need to utilize hot gas cleanup processes. Again, this demanding service has not been reliably demonstrated in a commercial application, resulting in less efficient approaches being used for current plant designs.

Cost-Effectiveness

IGCC has the potential to utilize coal in a more efficient process and with lower emissions than conventional coal power plants. The combined cycle portion of the process is attractive from a capital cost perspective compared to a conventional coal plant, but the addition of gasification, coal feed equipment, gas cooling, gas cleanup, and the installation of a oxygen plant result in an overall cost that is higher than a conventional coal plant. The resulting higher efficiency as compared to a conventional coal plant can not offset the higher capital costs. The currently demonstrated capital cost is about 30 percent higher and the efficiency is approximately 5 percent better than a conventional coal plant. This cost and performance comparison does not result in a cost of electricity that is lower than a conventional coal plant. The reported cost for the Polk County IGCC Plant is about $1,800/kW and the net plant heat rate (NPHR) target at full load is 9,400 Btu/ kilowatt hours (kWh). The annual NPHR has ranged from 9,877 Btu/kWh to 10,725 Btu/kWh. The target for IGCC NPHR in the future is about 8,000 Btu/ kWh. Future capital costs are expected to be about the same as conventional coal units of similar size. When those conditions are realized, IGCC will be a cost-effective alternative to conventional coal.

Environmental Compatibility

The overall environmental impacts from an IGCC design would be expected to range somewhere between those of a natural gas combined cycle turbine resource and a coal resource. Environmental impacts would include air emissions, water/wastewater discharge, and solid waste disposal.

Air

Estimated air emissions for a 250 mW IGCC resource are shown in Table 2-13. The emissions shown are based on the Tampa Electric Polk Station project. A major source PSD permit would be required. Based on a BACT analysis additional control may be required including SCR for NO_x control and catalytic oxidation for CO control. There would also be PM_{10} emissions from the cooling tower. There could also be other minor sources of air emissions from the IGCC process and miscellaneous support equipment such as coal handling and preparation equipment, diesel/natural gas emergency generators and fire pumps. These emissions would be similar to the installation of a conventional coal fired plant.

Table 2-13
IGCC Estimated Annual Air Emissions (tons/year)

Sulfur Dioxide (SO_2)	Nitrogen Oxide (NO_x)	Carbon Monoxide (CO)	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPS)	Mercury (Hg)	GHGs
1242	790	364	133	NA	0.05	1,553,000

Note:
Emissions are based on Tampa Electric Polk Power Station integrated gasification combined cycle (IGCC) Project. HAPs emissions were not reported but are expected to be lower than a conventional pulverized coal boiler but higher than a conventional natural gas combined cycle turbine. Carbon Dioxide (CO_2) emissions are estimated to be 20 percent less than conventional pulverized coal boiler.

Water

An IGCC power plant using wet cooling would have similar but lower water use requirements as a coal-fired facility. In a typical combined cycle plant, approximately one-third of the total generation capacity comes from the steam cycle, two-thirds is generated directly by the combustion turbine generator equipment. The water would be used for cooling, steam cycle makeup, and other small volume uses. As with conventional coal-fired power plants, dry cooling or zero liquid discharge systems could be used at IGCC power plants. An industrial wastewater discharge permit would be required for a typical wet-cooled plant. An adequate source of water would also be required for a typical wet-cooled plant. Stormwater and SPCC plans will be required.

Footprint

A 250 mW IGCC facility would require approximately 180 acres.

General Permitability

Permitting of an IGCC power plant requires numerous permits and approvals from federal, state, and local regulatory agencies. A major source PSD air construction permit would be required. However, based on the relatively low emissions compared to other alternatives, the application, review, and public comment processes would be fairly straight forward.

The permit application, agency review and follow-up, and public comment process would probably not be as extensive as a new conventional coal-fired resource. EPA regional offices and state regulatory agencies will likely provide favorable reviews of both the CFB and IGCC technologies.

Southern Montana Electric G&T

SME does not anticipate adding this technology to their generation portfolio. IGCC is the least cost-effective technology as compared to a more conventional coal-fired power plant, represents a technology which needs further development, and has limited environmental benefits.

Capable of Fulfilling Purpose and Need

The IGCC technology is judged not capable of fulfilling the Purpose and Need for new generation. The reasons for this are the requirement for a high level of reliability and long term, cost-effective, and competitive generation of power. The issues associated with IGCC technology discussed above, have not demonstrated acceptable reliability. The current approaches to improving reliability in these areas result in less efficient facilities, negatively impacting the cost-effectiveness. The Department of Energy (DOE) has a program, Vision 21, with the goal of providing clean coal power-generation alternatives by the year 2015. One of the program objectives includes improving the cost-competitiveness of IGCC. However, the current DOE time frame does not support SME's schedule and needs.

3.0 Conclusions

The projected levelized costs for new utility power generation plants in the Montana area are shown in Table 3-1. The power-generation technologies presented with their respective competitive costs are wind, solar, hydroelectric, geothermal, biogas, MSW, NGCC, microturbines, PC, CFB and IGCC. However, wind, solar, and hydroelectric power have average capacity factors which range from 26% to 50% and can not be considered for base load service.

Table 3-1
Levelized Costs for New Utility Power Generation Plants
NWPP Region

	Levelized Costs ($mWh)				
Type of Power Plant	Capital Cost	Fixed O&M Cost	Variable / Fuel Cost	Total Busbar Cost[1]	Average Capacity Factor
Wind	35.9	7.7	7.0 [2]	50.6	26%-36%
Solar – Photovoltaic	N/A	N/A	N/A	350.0	20%-35%
Solar – Thermal	N/A	N/A	N/A	105.0	20%-35%
Hydroelectric	17.0	2.6	4.0	23.6	40%-50%
Geothermal	N/A	N/A	N/A	65.0	90%
Biomass	N/A	N/A	N/A	90.0	90%
Biogas	37.0	6.6	3.0	46.5	90%
Municipal Solid Waste (MSW)	32.8	38.9	13.0	84.8	90%
Natural Gas Combined Cycle (NGCC)	19.0	2.3	41.0	62.3	90%
Microturbines	49.1	8.4	55.7	113.2	90%
Pulverized Coal (PC)	25.1	4.6	12.8	50.1	90%
Circulating Fluidized Bed Coal (CFB)	25.2	4.6	12.8	42.6	90%
Integrated Gasification Combined Cycle Coal (IGCC)	42.8	3.3	19.8	65.9	<80%

Source: Refer To Tables 2-1, 2-5 and 2-8

Note:

[1] Busbar Cost – wholesale cost to generate power at the plant.

[2] Variable cost for wind power represents transmission costs

$/mWh – dollars per megawatt hour

O&M - operations and maintenance

A comparison of the altenate technologies regarding their capability of meeting the SME purpose and need criteria is shown in Table 3-2. Only the PC and CFB coal technologies are capabile of meeting all of the criteria. Although NGCC offers the average capacity factor SME requires and the capital cost component of the levelized cost of NGCC power is attractive as compared to a CFB or pulverized coal plant. This coupled with the volatility of natural gas prices results in NGCC being a costly option for SME's member cooperatives and customers.

TABLE 3-2

Comparison of Alternate Power Generation Technologies *Southern Montana Electric G&T*

	Capable of Meeting Purpose and Need Criteria							
Type of Power Plant	250 mW in 2009	Baseload Operation	Environmentally Permitable	Cost-effective	Fuel Cost Stability	High Reliability	Commercially Available	Meets All Criteria
Wind	Yes	No	Yes	Yes	Yes	Yes	Yes	No
Solar -Photovoltaic	No	No	Yes	No	Yes	No	Yes	No
Solar-Thermal	No	No	Yes	No	Yes	No	Yes	No
Hydroelectric	No	No	Difficult	Yes	Yes	Yes	Yes	No
Geothermal	No	Yes	Yes	N/A	Yes	Yes	N/A	No
Biomass	No	Yes	Yes	No	Yes	Yes	Yes	No
Biogas	No	Yes	Yes	Yes	Yes	Yes	Yes	No
Municipal Solid Waste (MSW)	No	Yes	Difficult	No	Yes	No	Yes	No
Natural Gas Combined Cycle (NGCC)	Yes	Yes	Yes	Yes	No	Yes	Yes	No
Microturbines	No	No	Yes	No	No	Yes	Yes	No
Pulverized Coal (PC)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Circulating Fluidized-Bed (CFB) Coal	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Integrated Gasification Combined Cycle Coal	Yes	Yes	Yes	No	Yes	No	Yes	No

Note:
Based on alternate power plant options located within or adjacent to the SME System.

4.0 Notes

Load & Capability data are from Southern Montana Electric G&T "2004 Load & Capability Forecast". This forecast is based largely on the information obtained in the Central Montana Electric historical files, member historical files and projections made utilizing levelized load factors. This report was prepared in October of 2004 utilizing the latest information from member cooperatives for future load growth.

The emissions factors for the PC fired boiler permit were obtained from the permit issued to Bull Mountain Development Company for the Roundup Power Project.

The emissions factors for the CFB boiler were determined from information obtained from Alstom and Foster Wheeler. These factors were budgetary predictions of the emissions which would later be guaranteed by the supplier under contract. These preliminary emission factors were obtained during the months of August and September, 2004.

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